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Effects of adjacent mud rocks on CO_2 injection pressure: model case based on a typical U.S. Gulf Coast salt diapir field under injection

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Abstract

Geological carbon storage aims at long-term storage of carbon dioxide (CO_2) in deep geological formations to reduce anthropogenic CO_2 emissions into the atmosphere. The viability of CO_2 storage hinges on how much of the CO_2 can be injected into the storage formation. However, the rate of CO_2 injection can be limited by low injectivity of the storage formation and limits placed on the injection pressure to maintain seal integrity. Therefore, pressure evolution during CO_2 injection is an important consideration for CO_2 storage operation and is investigated in this study. We use geological characteristics of a typical oil field near a salt diapir in the Gulf Coast basin in the Southern United States. In this case CO_2 is injected into a complex sedimentary rocks deposited in a fluviatile environment, juxtaposing volumes of high- and low-permeability rocks. The rock volume in which CO_2 injection is taking place can be modelled, for the purpose of this study, as a simple reservoir surrounded by mud rocks which exhibit small, but finite, permeability and high compressibility. The mud rock is expected to behave as a capillary seal preventing upward CO_2 migration, but may allow significant pressure dissipation. This pressure attenuation can be important from an operational standpoint as a fault in the vicinity of the injection well requires an accurate estimate of pressure evolution to avoid leakage along the fault.

Most numerical simulations of geological CO_2 storage have focused on the behavior of fluids within a storage formation and assumed that overlying and underlying rocks are impermeable and incompressible. Such a reservoir model has immediate pressure buildup and drawdown corresponding to start and end of injection. Numerical simulations using reservoir parameters and a simple geomechanical model based on rock and fluid compressibilities were performed with the commercial simulator GEM from CMG. They show that overlying and underlying mud rocks attenuate pressure build-up within a reservoir during injection and extend the period of pressure recovery after the end of injection. The attenuation of pressure propagation within a target formation can reduce the probability of creation and/or reactivation of geological discontinuities. In addition, strong pressure gradients detected just outside the storage formation require high numerical resolution at the boundaries between the storage formation and mud rocks, otherwise extensive numerical diffusion will lead to unphysical pressure dissipation. It is therefore not just important to include the surrounding rocks but also to discretize them appropriately, and this is currently not standard practice.

Keywords: compressible mudrock, pressure diffusion, area of review, caprock failure

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1. Introduction

Structural trapping associated with a caprock plays a significant role in storing injected CO_2 permanently. If the caprock contains fractures and/or faults, which may be connected to another permeable layer, it cannot act as a sealing boundary any more. Many studies, therefore, have focused on how such geological discontinuities impact fluid flow as well as caprock integrity depending on their petrophysical or geometric properties (Rutqivst & Tsang [1]; Chang & Bryant [2]). Two major concerns are whether the maximum pressure build-up due to injection will fracture caprock and the size of the area of review that is determined by lateral propagation of pressure-pulse. In the case considered here the area of review may be limited by the vicinity of a fault that may be reactivated by a pore-pressure increase. Most of geological CO_2 storage studies focus on the two-phase flow inside the storage formation, effectively assuming an impermeable ambient material, which confines the pore-pressure. In this study we focus on the role of ambient rocks on the pressure dissipation. Caprocks are often mudrock with non-negligible permeability and finite compressibility that will absorb injection-induced pressure (Figure 1). Studies of pressure build-up excluding the over/under burden may therefore overestimate pressure build-up. Here we quantify the effect of compressible and permeable mudrocks in the over/under burden on the pressure distribution throughout the reservoir as a function of the amount of mudrocks and their compressibility.

2. Analytical & Modeling Approach

2.1. Analytical Approach

Assuming constant external stresses and uniaxial deformation in the vertical we study the pressure evolution using a simple pressure diffusion model. In this case the equation for pore pressure dissipation in single phase flow in a porous medium is obtained from the equation of mass conservation and Darcy's law. Pressure propagation through the reservoir which is assumed as a homogeneous and isotropic medium can be estimated by following one-dimensional linear diffusion equation.

$$\frac{\partial p}{\partial t} = D\frac{\partial p^2}{\partial^2 r} \tag{2.1.1}$$

The microseimic events (here, injection-induced pressure propagation) will be characterized by (Shapiro *et al*. [3])

$$r_f = \sqrt{4\pi D t} \tag{2.1.2}$$

where, r_f = distance from the injection point to front

t = traveling time

$$D = \frac{k}{\mu c_t \phi} = \text{pressure diffusivity} \tag{2.1.3}$$

In the pressure diffusivity term, we need to define the total compressibility, c_t, of the porous medium. Generally, we have two forms of total compressibility depending on the simplifying assumptions (Domenico & Schwartz [4]):

1) $c_t = c_f + \dfrac{c_p}{\phi}$

2) $c_t = c_f + \dfrac{(1-\phi)c_p}{\phi}$

A simple combination of fluid and matrix (grains + pores) compressibilities produces the 2nd type of total compressibility. However, if the motion of both fluids and grains are considered simultaneously and both are conserved, we will have the 1st type of total compressibility. Therefore, the assumption of incompressible grains implies that the medium compressibility is provided entirely by rearranging of grains into more efficient packing. Figure 2 shows that the difference between these types of compressibility formulations is small for the range of porosities $\phi < 0.3$ of interest here.

The scaling for the horizontal propagation of the pressure front given in equation (2.12) is will be affected by the presence of an ambient mud rock with non-negligible diffusivity. To quantify these dissipative losses we assume a general power-law for the horizontal pressure propagation of the form:

$$r_f = mt^n \tag{2.1.4}$$

where, m, n = constant (if the surrounding layers are incompressible, n = 0.5). In log-log scale, the above equation can be expressed as follows:

$$\log r_f = a + b \log t \tag{2.1.5}$$

Here, we use the exponent, b, to quantify the retardation of the pressure pulse due to the dissipation into the surrounding ambient mud rocks.

2.2. Simple Model Approach

Simplified models aim to determine whether mudrock compressibility can be neglected for estimates of a reservoir capacity as well as assessment of leakage driven by injection-induced pressure. For this study, we create two conceptual models:

1) Two-dimensional linear model of layered system juxtaposed by a vertical fault (Figure 3(a))
2) Cylindrical model without a fault (Figure 3(b)).

Petrophysical properties of reservoir and fluids are extracted from experimental data of Cranfield field, MS where in-situ CO_2 injection has been undergone, well operations are modified using applicable field data (Table 1 & 2). To represent single-phase flow regime brine will be injected into brine-saturated reservoir. In this study we have two major parameters: fraction of mudrock, f_m, and diffusivity ratio, D_m/D_s.

1) $$f_m = \frac{(thickness\ of\ mudrock)}{(thickness\ of\ sandstone)} = \frac{L_m}{L_s} = \frac{L_1 + L_3}{L_2} \tag{2.2.1}$$

2) $$\frac{D_m}{D_s} = \frac{\left(\dfrac{k_m}{\mu c_{t,m}\phi_m}\right)}{\left(\dfrac{k_s}{\mu c_{t,s}\phi_s}\right)} = \frac{k_m c_{t,s}\phi_s}{k_s c_{t,m}\phi_m} \tag{2.2.2}$$

where, k_i = permeability
$c_{t,i}$ = total compressibility
ϕ_i = porosity
i = m (mudrock), s (sandstone)

3. Results & Analysis

3.1. Faulted 2D Layer

Here we take the whole domain to be simple layered system juxtaposed by a sealing fault. The variables are diffusivity ratio (D_m/D_s) and fraction of mudrock layers (f_m). The diffusivity ratio will vary with three values of mudrock compressibility (1/psi), 8.44×10^{-5} (base case), 8.44×10^{-4}, 8.44×10^{-3} and the fraction of mudrock layers will vary with changing thickness of mudrock layers (Table 3). No fluid is injected in the first ten years in order to achieve initialize the reservoir with a hydrostatic pressure equation, and then we have six-month-injection then shut-in. Pressure data has been collected at the point near a sealing fault within a target formation.

3.1.1. Effect of Mudrock Compressibility

Figures 4(a) & Figure 5(a) show that pressure diffusion into over/under burdens reduces maximum pressure reached during the injection in the target formation. As the compressibility of the mudrock increases, the maximum pressure is reduced and the duration of the pressure-perturbation increases (pressure build-up to drawdown) (Figure). This pressure attenuation can be interpreted by intact rock failure criteria (Figure 4(b)). The failure equation is as follows:

$$\sigma_t \geq \mu_i (S_n - p_p) + S_0 = \mu_i \sigma_n + S_0 \tag{3.1.1}$$

where, σ_t = effective shear stress
μ_i = friction coefficient
S_n = total normal stress
p_p = pore pressure
σ_n = effective normal stress
S_0 = cohesion

As surrounding mudrock absorbs more injection-induced pressure, we have less increase of pore pressure and larger effective normal stress. Therefore, the probability of shear failure of the formation due to injection would be reduced.

3.1.2. Effect of Fraction of Mudrock

Another parameter is a volume of surrounding mudrock. One might expect that more mudrock may absorb more pressure. However, as shown in Figure 5(b), the value of the maximum pressure is not strongly affected by the amount of ambient mudrock. In Figure 6, shows that the pressure in the mudrock is only perturbed in a thin boundary layer, δ, just outside the target formation. As long as the thickness mudrock exceeds this boundary layer it will not affect the pressure diffusion.

3.2. Cylindrical Model

For more realistic studies, we use radial coordinates which has been generally adapted for well test models. In this radial model, we exclude geological discontinuities and each section is a homogeneous medium. The only variable is diffusivity ratio which will vary with five values of mudrock compressibility (1/psi), 8.44×10^{-10}, 8.44×10^{-5} (base case), 8.44×10^{-4}, 8.44×10^{-3}, 8.44×10^{-2}. From the pressure data we extract contour lines for pressure of 3781.68 psi (Figure 7(a)). Within a sandstone layer, the maximum speed of the pressure front (r_f) can be estimated by equation (2.1.2). However, radius of review will be reduced by pressure diffusion into over/under burdens. Also, pressure dissipation will increase time until the pressure front encounters a pre-existing fault. Figure 7(b) shows how the exponent, n in equation (2.1.4) and b in equation (2.1.5), changes as a function of diffusivity ratio. If the surrounding mudrock is assumed to be incompressible, the value of the exponent is 0.5. The presence of more compressible mudrock results in reduction of the exponent due to pressure diffusion into the mudrock.

4. Conclusion

This numerical study confirms us that compressible mudrock layers will affect pressure response during and after injection. Even though typical mudrock will not allow leaks of supercritical CO_2 due capillary entry pressure, the presence of compressible mudrock layers surrounding a target formation will play a significant role in pressure propagation within the target reservoir. First, the compressible mudrock absorbs injection-induced pressure, and thus we have less area of elevated pressure. Second, in the sense of shear failure criteria less maximum pressure build-up will reduce failure probability of pre-existing weak or discontinuous structures. Third, the vertical pressure diffusion into the compressible mudrock will result in slower lateral speed of pressure propagation. This implies that region of elevated pressure will take more time to approach the fault and/or fracture. However, properties of the mudrock zone requires more studies because behaviours of pressure transition between sandstone layer and mudrock layer and will vary depending on the thickness of the mudrock zones.

We find that strong pressure gradients are present just outside the target reservoir and require high grid resolution just outside the reservoir. If these gradients are not sufficiently resolved numerical diffusion will lead to artificial dissipation of pressure and pressure build up is underestimated.

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Table 1. GEM linear two-dimensional model parameters

Parameter			*Value*	*Description*
Reservoir	Grid	Block size	10ft× 10ft× 10ft	Cartesian griding system
		Block number	201× 1× 100	One grid block in y-direction
	Whole reservoir scale		2001ft× 10ft× 1000ft	
	Depth at reservoir top		9400 ft	From surface to reservoir top
	Dip		0 degree (Horizontal)	
Well	Injector	Location	(32 1, 54)	- Injector is 320ft away from a side boundary - Water injection - Slightly (10ft) below the middle of sand layer
		Injection duration	0.5 year	
		Perforation depth	9940 ft	
		Injection rate	5 bbl/day	
	Producers	Location	Sides of each sand layer	For hydrostatic boundaries of the sand layers
			(100, 1, 1)	For open top of the fault
			(100, 1, 100)	For open bottom of the fault

Table 2. GEM radial model parameters

Parameter			*Value*	*Description*
Reservoir	Grid	Cell size	20ft× 10 deg× 5	- Cylindrical griding system
		Number of cells (x× y× z)	100× 36× 21	
	Reservoir size		2000ft× 360 deg× 105ft	- Radius× θ × height
	Depth at reservoir top		9400 ft	- Distance from surface
	Dip		0 degree (Horizontal)	
	Thickness	Sand	5 ft	- Sand layer is located at the middle of the reservoir
		Mudrock	50ft + 50ft	
Well	Injector	Location	Center of sand layer	- Water injection
	Operation Option	Bottomhole pressure	3791.15psi	- Reservoir pressure + 10psi
	Producers	Location	External boundaries	- For hydrostatic boundaries

Table 3. Reservoir parameters varied for sensitivity tests using GEM

Parameters			*Value*	*Description*
Compressibility of mudrock (c_m), 1/psi			8.44 X 10^{-5},10^{-4},10^{-3}	- 8.44 X 10^{-5} of mudrock compressibility is for the standard case (Chierici *et al.*, [5])
Fraction of mudrock (f_m)			7.5, 0.75, 0.375, 0.1875	- Fraction is the ratio of thickness of mudrock layers to thickness of sand layer - Thickness of sand layer is constant
Horizontal permeability (k_h), md	Fault		10^{-3} to 10^{2}	- $(k_v/k_h)_{Reservoir} = 0.01$ - $(k_v/k_h)_{Fault} = 1$ - Relationship between permeability and porosity is based on experimental data (Revil & Cathles, [6])
	Reservoir	Mudrock	2.2	
		Sand	55	
Porosity (ϕ)	Fault		0.062 to 0.258	
	Reservoir	Mudrock	0.161	
		Sand	0.240	

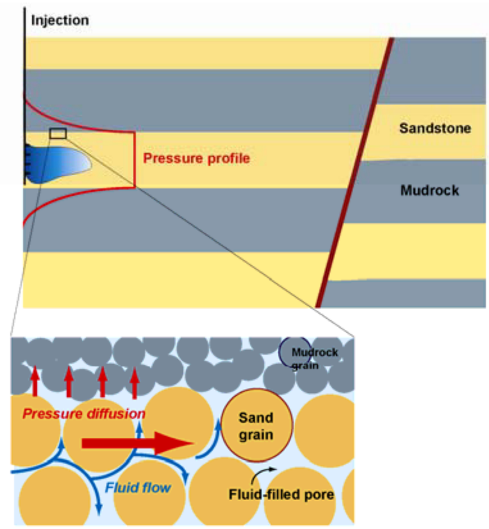

Fig 1. Schematic description of pressure diffusion during injection; even if mudrock blocks vertical migration of plumes of injected fluids, injection-induced pressure will diffuse into it.

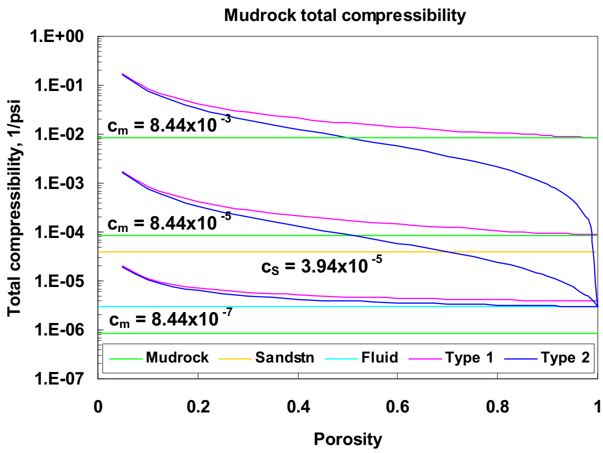

Fig 2. Total compressibility values as a function of porosity and mudrock compressibility: magenta lines are for the 1st type of total compressibility while blue ones are for the 2nd type of total compressibility. Type 2 relies more on fluid compressibility

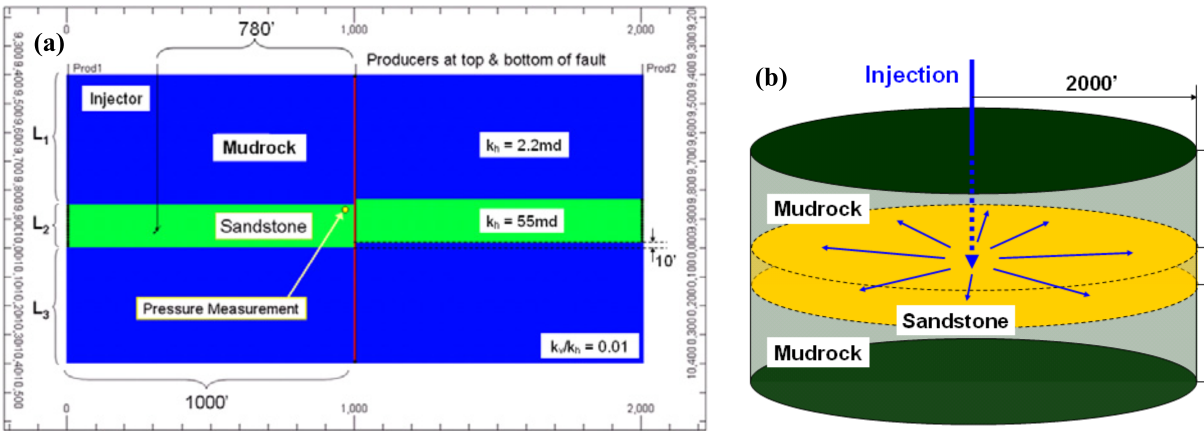

Fig 3. Schematic description of the simple numerical models: (a) two-dimensional linear model and (b) cylindrical model; reservoir parameters and well operations for each model are based on in-situ data; the major variables are 1) diffusivity ratio (D_m/D_s) reverse to rock compressibility ratio (c_m/c_s) and 2) fraction of mudrock ($f_m = (L_1+L_3)/L_2$)

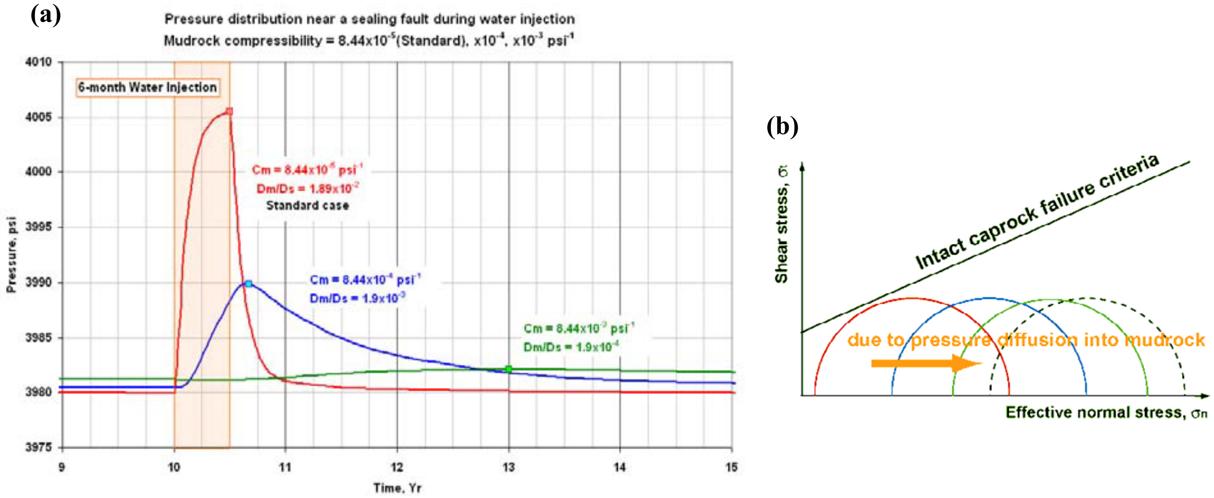

Fig 4. (a) Pressure profile with variation of diffusivity ratio (D_m/D_s) and (b) intact rock failure criteria; more compressible mudrock (less diffusivity ratio) results in less value of the maximum pressure as well as longer period of the pressure pool. In the sense of failure criteria, more compressible surrounding mudrock allows less increase of pore pressure, and thus we have less probability of shear failure due to injection.

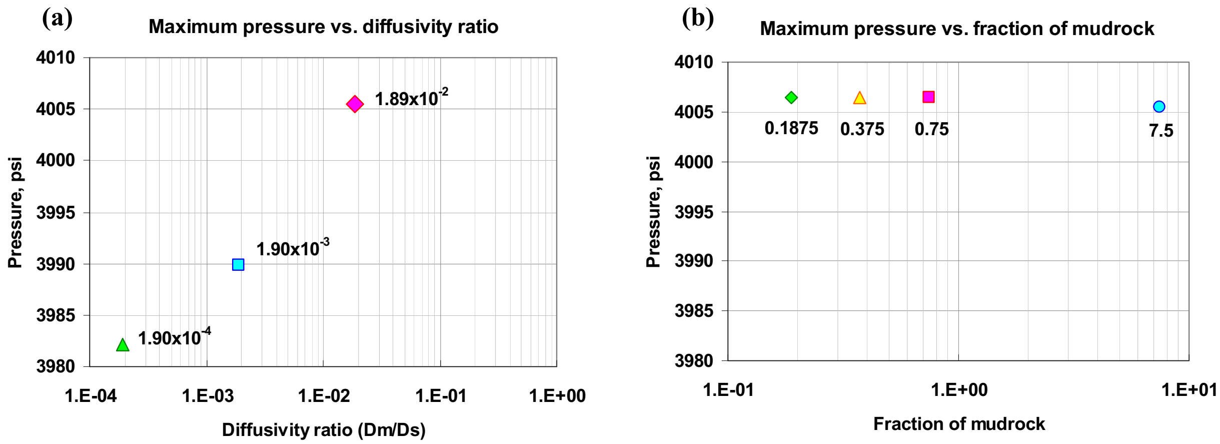

Fig 5. Maximum pressure data near the fault within a sandstone layer: in case (a) we vary mudrock compressibility, and as diffusivity ratio (D_m/D_s) becomes smaller (more compressible mudrock), we have less value of the maximum pressure; in case (b) we vary fraction of mudrock (f_m), and even if we have more surrounding mudrock, the value of the maximum pressure will not vary much.

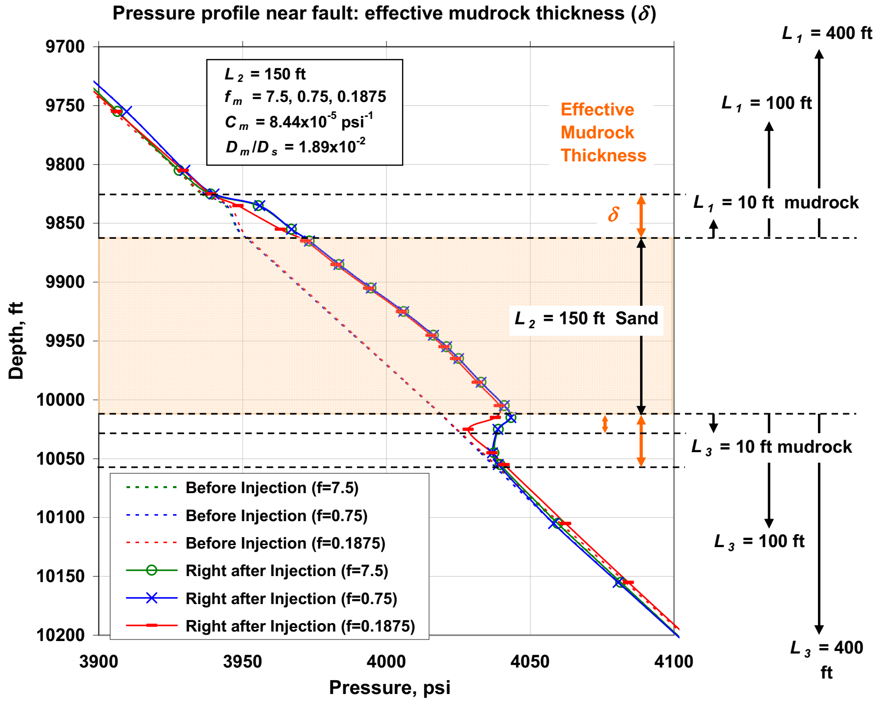

Fig 6. Pressure profile shows that the effect of the fraction of mudrock on pressure propagation within the target reservoir as well as pressure diffusion into the surrounding compressible mudrock; only thin layer (effective mudrock thickness, δ) adjacent to the target reservoir has pressure increase, which implies that the fraction of mudrock will not be as important as the diffusivity ratio

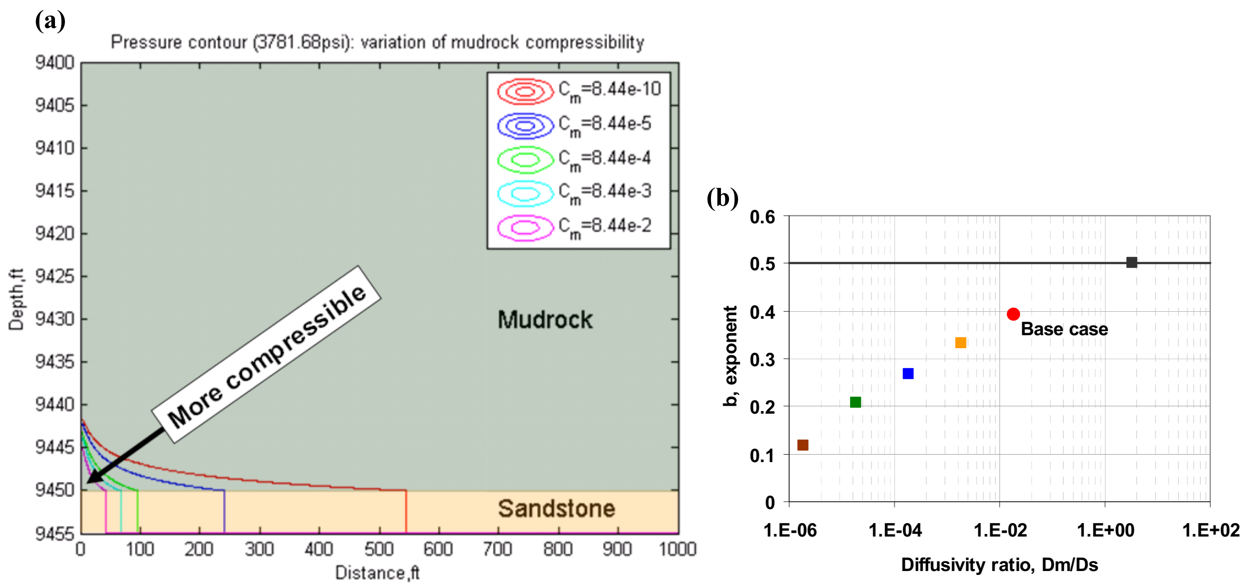

Fig 7. (a) Pressure contour map using data from the cylindrical model and (b) the exponent of the pressure front equation; more compressible mudrock will absorb more injection-induced pressure, and thus the speed of the pressure front becomes slower as well as the area of review will be reduced; the exponent value of 0.5 represents the mudrock is assumed to be incompressible. More compressible mudrock results in less value of the exponent due to more pressure diffusion into the mudrock.